INTERMOUNTAIN POWER SERVICE CORPORATION

August 31, 2004

Mr. Richard Sprott, Director
Division of Air Quality
Utah Department of Environmental Quality
P.O. Box 144820
Salt Lake City, UT 84114-4820

Attention: Harold Burge, Compliance Section

Dear Director Sprott,

TEST REPORT: IPSC Unit 2 CO Emissions

On April 15, 2004, Intermountain Power Service Corporation (IPSC) received from UDAQ a modified Title V Operating Permit for the Intermountain Generating Station (IGS) near Delta, Utah. This permit, #2700010002, allowed IPSC to operate a new over fire air system on IGS Unit 2 installed under approval of AO #DAQE-AN0327009-04. As required by #2700010002 Condition II.B.2.h.1(6), IPSC has tested the over fire air system impact on carbon monoxide (CO) emissions. The Intermountain Power Service Corporation (IPSC) is hereby submitting the results and analyses of the testing to satisfy that permit condition.

BACKGROUND

IPSC received approval to install and operate over fire air (OFA) to control nitrogen oxides (NO_X) emissions on IGS Unit 1 in 2003. That system was tested to ascertain how CO flue gas concentration changed based upon OFA operating status and boiler oxygen levels. The O_2/CO relationship curve developed from that testing is used to determine CO emissions on a continuous basis in order to assure compliance with a CO permit limit.

OFA was installed on IGS Unit 2 in March 2004. It began start-up and tuning in April and May, and was operational by June. Testing to confirm CO flue gas concentration and emissions were conducted June 14 and 15, 2004. Mr. Harold Burge of your compliance staff was on-site to observe. The purpose of testing was to verify that the Unit 2 O_2/CO relationship matched the curve developed for Unit 1.

TEST SUMMARY

Testing Requirements

IPSC tested flue gas CO concentration in IGS Unit 2 according to the Title V permit conditions. Those conditions required:

850 West Brush Wellman Road, Delta, Utah 84624 / Telephone: (435) 864-4414 / FAX: (435) 864-6670 / Fed. I.D. #87-0388573

1. Test within 180 days of completing startup of the OFA system.

2. Provide a notification of testing and a test protocol to UDAQ 30 days prior to testing.

3. Identify in the test protocol the stack to be tested, and the test methods to be used, which must include:

   Method 1 conforming test location
   Method 2 flow determination
   Method 10 CO determination

4. Production rate must be 90 percent or greater of the last 3 years.

5. Unit 2 data must be verified to fit the curve developed for Unit 1.

Permit Compliance

1. *Test within 180 days of completing startup of the OFA system.*
   Startup of the Unit 2 OFA system began upon receiving the Title V Operating Permit in April, and ended with the fuel/air balancing of the last burner front in June. Testing occurred in June, well within the 180-day requirement.

2. *Provide a notification of testing and a test protocol to UDAQ 30 days prior to testing.*
   IPSC provided a test protocol and proposed test date to UDAQ on May 7, 2004, 38 days prior to testing.

3. *Identify in the test protocol the stack to be tested, and the test methods to be used.*
   The submitted protocol identified the Unit 2 flue as the test point, a Method 1 location. Methods that were proposed included Method 2 for volumetric flow, Method 4 for moisture, and Method 10 for CO. In discussions with your staff, we understood that the protocol was acceptable. IPSC also requested that the test calculation use calculated saturated moisture values from the Method 4 protocol, since previous Method 4 results indicate moisture values average at or above calculated saturation. This was also acceptable to your staff.

4. *Production rate must be 90 percent or greater of the last 3 years.*
   Production during the testing period averaged 950 MWe. Normal peak production during the previous 3 years was 900 MWe.

5. *Unit 2 data must be verified to fit the curve developed for Unit 1.*
   Testing on Unit 2 consisted of verifying CO concentrations at each OFA and boiler O_2 operating condition as graphed for Unit 1. The data spread for CO resulting from Unit 2 testing were found to lie in the expected confidence intervals predicted by the curves developed on Unit 1. These data are summarized in the attached spreadsheets, and detailed in the attached test data compilations. Graphical representations of these results are also included.

SUMMARY RESULTS

Test Condition	Unit 2 CO (ppm)	95% Confidence Interval	Curve Fit (Y/N)
No OFA @ 2% O_2 range	140.1	44.8 - 444.3	Y
No OFA @ 2.5% O_2 range	3.2	0.0 - 240.2	Y
No OFA @ 3% O_2 range	9.8	0.0 - 218.9	Y
1/3 OFA @ 2% O_2 range	198.1	0.0 - 468.3	Y
1/3 OFA @ 2.5% O_2 range	24.4	0.0 - 318.0	Y
1/3 OFA @ 3% O_2 range	7.7	0.0 - 269.4	Y
2/3 OFA(partial) @ 2% O_2 range	277.7	152.0 - 343.3	Y
2/3 OFA(partial) @ 2.5% O_2 range	37.5	0.0 - 169.1	Y
2/3 OFA(partial) @ 3% O_2 range	18.1	0.0 - 141.5	Y
2/3 OFA(open) @ 2% O_2 range	192.2	39.9 - 243.4	Y
2/3 OFA(open) @ 2.5% O_2 range	187.8	0.0 - 197.7	Y
2/3 OFA(open) @ 3% O_2 range	13.7	0.0 - 143.0	Y

If you require any further information concerning this report, please contact Mr. Dennis Killian, Superintendent of Technical Services at IPSC, at 435-864-4414, or dennis-k@ipsc.com.

Inasmuch as this letter may affect our Title V operating permit #2700010002, I hereby certify that, based upon the information and belief formed after reasonable inquiry, the statements and information in this and associated documents are true, accurate, and complete.

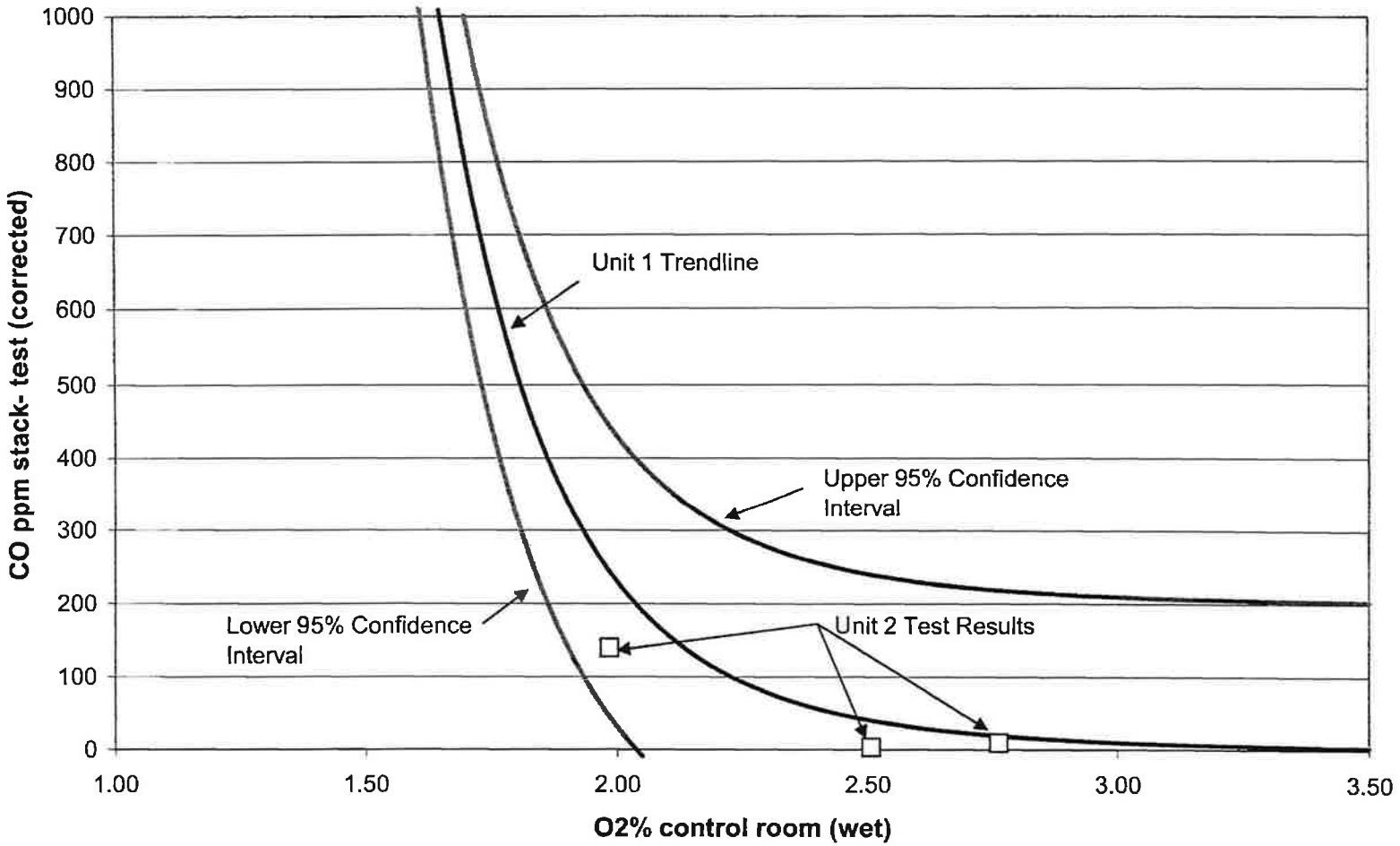
Cordially,

George W. Cross
President and Chief Operations Officer

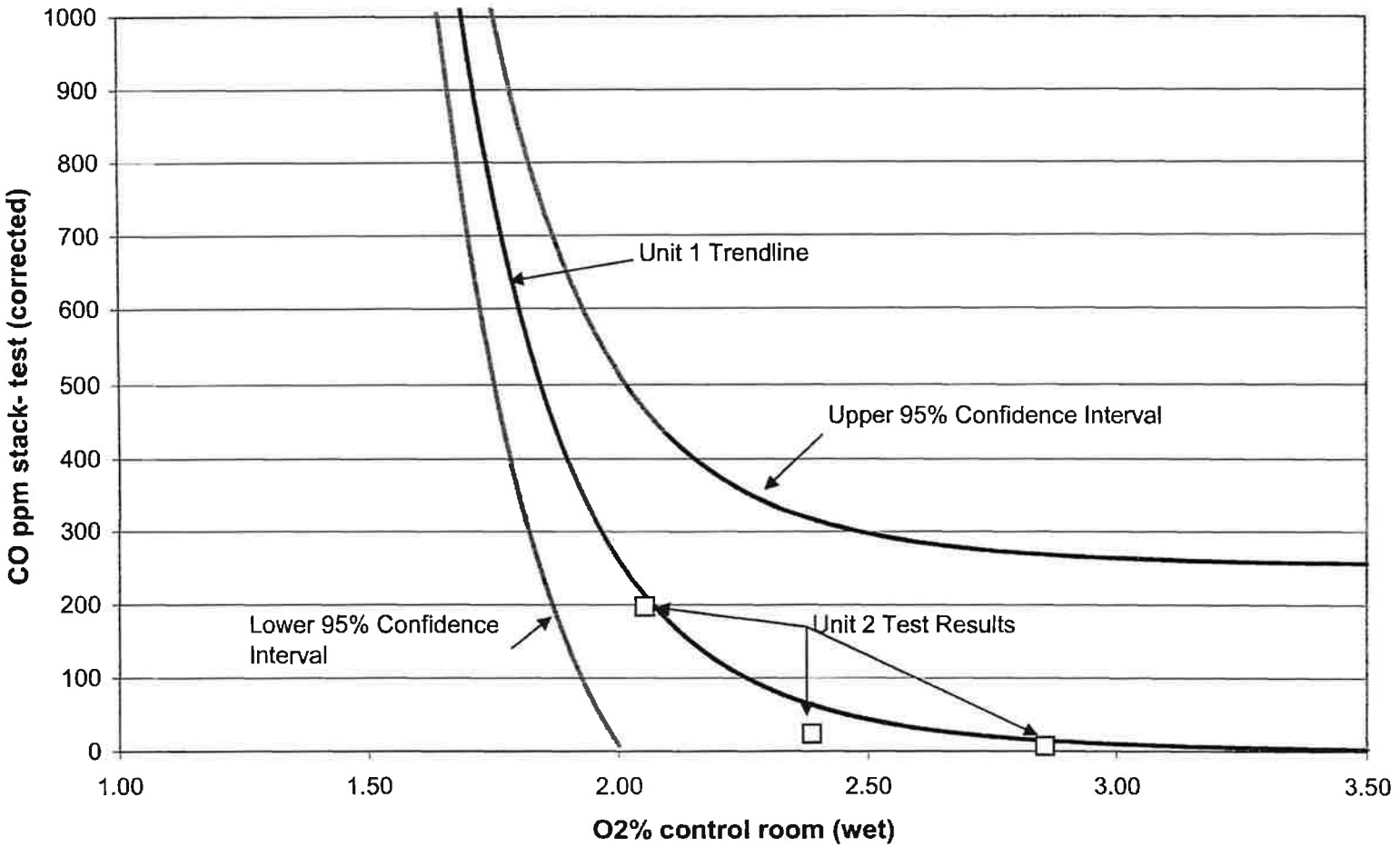
RJC/BP:jmj
Enclosures: Graphs
Test Report
Summary Spreadsheets
Test Data
Test Protocol

cc: Blaine Ipson, IPSC
Jerry Hintze, IPSC
Bruce Harvey, LADWP

IPP Unit 2 Boiler O2% vs CO ppm Curve Fit
NO Overfire Air (5% cooling) OFA 1/3, 2/3, & inlet dampers closed

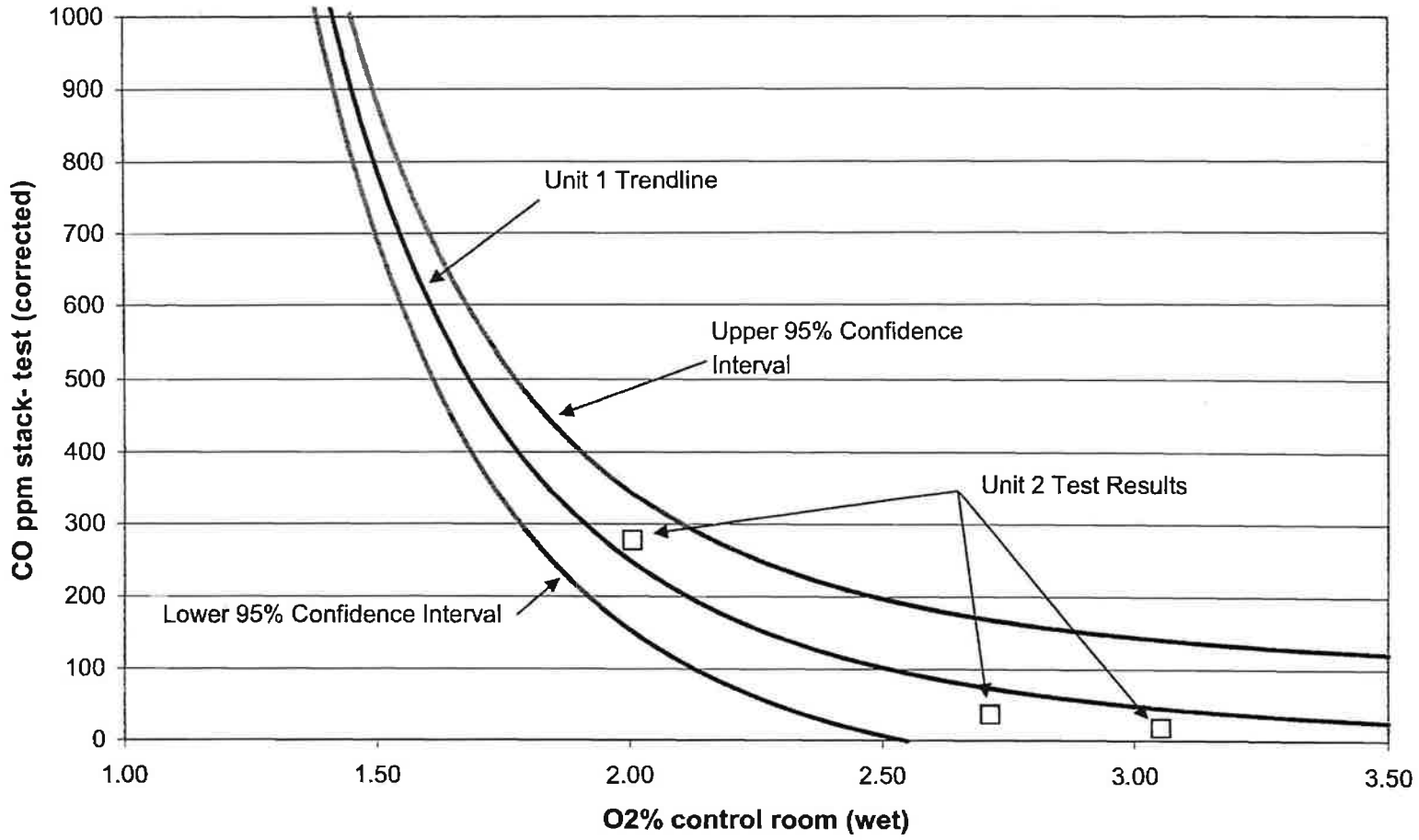


IPP Unit 2 Boiler O2% vs CO ppm Curve Fit
1/3 Overfire Air (10%) OFA 1/3 and Inlet Dampers Open; 2/3 Dampers closed



2IP6_000005

IPP Unit 2 Boiler O2% vs CO ppm Curve Fit
2/3 Overfire Air Throttled (12%), OFA 1/3 Damper Closed; 2/3 Damper Partial and Inlet Dampers Open



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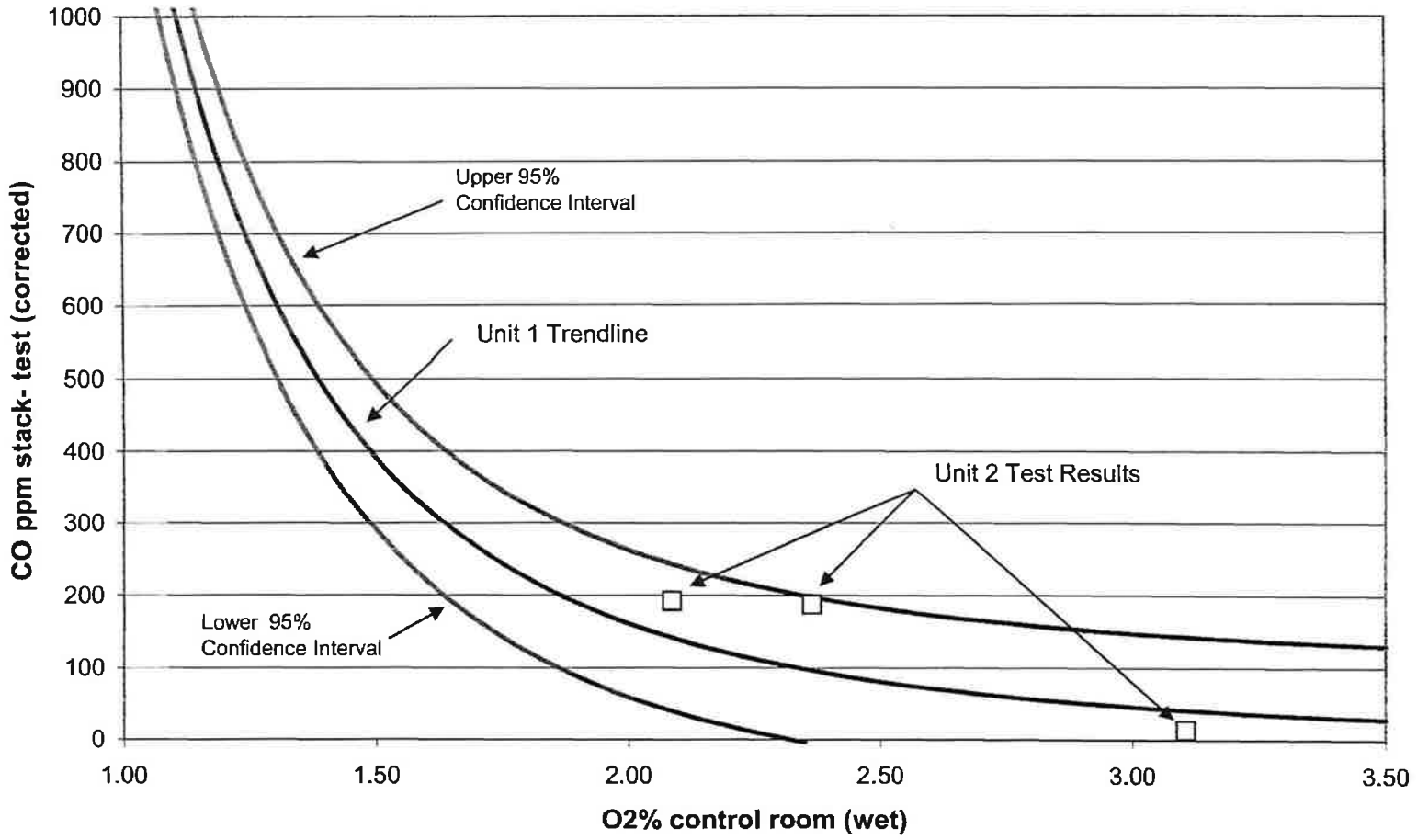
IPP Unit 2 Boiler O2% vs CO ppm Curve Fit
2/3 Overfire Air Open (14%), OFA 1/3 Damper Closed; 2/3 Damper and Inlet Dampers Open



CARBON MONOXIDE EMISSION TESTING CONDUCTED ON INTERMOUNTAIN POWER SERVICE CORPORATION'S BOILER UNIT NO. 2 LOCATED IN DELTA, UTAH

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1.0 Introduction

1.1 Summary of Test Project

Intermountain Power Service Corporation (IPSC) conducted carbon monoxide (CO) testing as required by permit. Testing was performed following Relative Method 10 protocol. The purpose of testing was to determine if CO concentrations in Unit 2 agreed with curves developed during Unit 1 CO testing that reflect a relationship between CO emissions and certain operating conditions. Testing occurred on June 14 and 15, 2004.

1.2 Test Project Organization

Major lines of authority and communication are outlined below. The project team was organized along lines of authority which distributes responsibility for completing test activities among key individuals in the team structure. Each team member was ultimately responsible to the Plant Manager.

Plant Owner: Intermountain Power Agency
480 E. 6400 S.
Murray, UT 84107

Operating Agent: Los Angeles Department of Water & Power
111 Hope St
Los Angeles, CA 90012

Plant Operations & Contact:
Intermountain Power Service Corp
850 W. Brush Wellman Rd
Delta, UT 84624
435-864-4414

Plant Manager:	George Cross, President & COO
Project Manager:	Blaine Ipson, Env. Supvsr.
Testing Coordinator:	Aaron Nissen, Env. Engineer
Data QA/QC:	Lynn Banks, Env. Analyst
Analytical QA/QC:	Rand Crafts, Env. Analyst

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Testing Team: Ron Westlund, Env. Engineer
Mike Ferrell, Env. Analyst
Rick Wright, Env. QC Technician
Rick Moody, Env. QC Technician
Garry Christensen, Perform. Engineer
Dave Spence, Perform. Engineer
Robert Jeffery, Lead Tech. Analyst

Regulatory Agency: Utah Department of Environmental Quality
Utah Division of Air Quality
PO. Box 144820
Salt Lake City, UT 84114

1.3 Background and Detail Overview

On April 15, 2004, Intermountain Power Service Corporation (IPSC) received from UDAQ a modified Title V Operating Permit for the Intermountain Generating Station (IGS) near Delta, Utah. This permit, #2700010002, allowed IPSC to operate a new over fire air system on IGS Unit 2 installed under approval of AO #DAQE-AN0327009-04. As required by 2700010002 Condition II.B.2.h.1(6), IPSC has tested the over fire air system impact on carbon monoxide (CO) emissions. The Intermountain Power Service Corporation (IPSC) is hereby submitting the results and analyses of the testing to satisfy that permit condition.

IPSC received approval to install and operate over fire air (OFA) to control nitrogen oxides (NOx) emissions on IGS Unit 1 in 2003. That system was tested to ascertain how CO flue gas concentration changed based upon OFA operating status and boiler oxygen levels. The O_2 / CO relationship curve developed from that testing is used to determine CO emissions on a continuous basis in order to assure compliance with a CO permit limit.

OFA was installed on IGS Unit 2 in March 2004. It began start-up and tuning in April and May, and was operational by June. Testing to confirm CO flue gas concentration and emissions were conducted June 14 and 15, 2004. The purpose of testing was to verify that the Unit 2 O_2 / CO relationship matched the curve developed for Unit 1.

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IPSC tested flue gas CO concentration in IGS Unit 2 according to the Title V permit conditions. Those conditions required:

1) Test within 180 days of completing startup of the OFA system.

2) Provide a notification of testing and a test protocol to UDAQ 30 days prior to testing.

3) Identify in the test protocol the stack to be tested, and the test methods to be used, which must include:

Method 1 conforming test location,
Method 2 flow determination, and
Method 10 CO determination.

4) Production rate must be 90% or greater of the last 3 years.

5) Unit 2 data must be verified to fit the curve developed for Unit 1.

The following source was tested for CO emissions:

- Intermountain Unit #2 Boiler Stack at 90 percent load or greater.

The testing was conducted on June 14 and 15, 2004. A pretest protocol was submitted to the UDEQ more than 30 days prior to testing. That protocol is attached.

IPSC performed emissions testing as set forth in the Code of Federal Regulations (CFR), Title 40, Chapter I, Part 60, Appendix "A." The following methods were used to determine CO emissions:

Method 1 - "Sample and Velocity Traverses for Stationary Sources" to confirm testing location
Method 2 - "Determination of Stack Gas Velocity and Volumetric Flow Rate (type "S" Pitot tube)"
Method 3A - "Determination of Oxygen and Carbon Dioxide Emissions from stationary Sources" (Instrumental analyzer Procedure)

Method 4 - "Determination of Moisture Content in Stack Gases" (Calculated Saturated Moisture was used)
Method 10 - "Determination of Carbon Monoxide Emissions from Stationary Sources"

1.4 Reason for Testing

CO Testing was performed to verify the relationship of CO emissions with certain operating conditions to agree with curves developed on Unit 1. Specifically, testing on Unit 1 produced evidence of a relationship between CO concentration in the flue gas under certain operating conditions that generally follows:

$$[C_{ppmvd}] = n * (O_2\%)^a$$

Where:

$[C_{ppmvd}]$ = concentration of CO in parts per million volume dry

n = curve specific factor obtained from the table below

$O_2\%$ = percent O_2 measured at the boiler exit

a = curve specific exponent obtained from the table below

Values for **n** and **a** factors

Position	n	a
No OFA	47259	-7.6817
1/3 OFA	66265	-7.9824
2/3 OFA - throttled	4029.2	-4.0112
2/3 OFA - full open	1372.4	-3.0919

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2.0 Description of Source

2.1 Plant Operation

There are two identical steam generators at IGS. Each unit is coal fired and rated at 950 megawatt. Each boiler is a Babcock & Wilcox design generating 6,900,000 lbs/hr steam flow at 2,975 psi and 1,005 degrees F, delivering to a 820MW nameplate turbine. The boiler has a pulverized coal 48 burner opposed wall configuration.

2.2 Pollution Control

Each boiler utilizes low-NOx burners and over-fire air for control of nitrogen oxides.

The combustion gas exits the boiler into a fabric filter for particulate control.

Flue gas leaves the ID fans and enters the wet limestone flue gas desulfurization scrubber for removal of acid gases and sulfur dioxide. The combustion gas is then discharged to the atmosphere through a 712 foot stack. Stack testing was done inside the concrete chimney support structure holding the two fiberglass stacks at the 352 ft. level.

2.3 Sampling & Monitoring Locations

Emissions sampling was conducted at the midpoint of the stack, in the Unit 2 flue liner. The sample location meets 40 CFR Part 60, Appendix A, Method 1 criteria.

Other operating parameters that are used for determining CO emisions were electronically monitored and recorded. These included:

Average boiler excess oxygen

Heat input

OFA portioned flow ratio

OFA damper status

3.0 Test Procedures

3.1 Test Conditions

These tests were run to determine how CO concentration changed under various operating conditions. Specifically, boiler excess oxygen and OFA operating status were set at specific points as follows:

No OFA at 2 %, 2.5%, and 3% O_2

1/3 OFA at 2 %, 2.5%, and 3% O_2

2/3 OFA Throttled at 2 %, 2.5%, and 3% O_2

2/3 OFA Open at 2 %, 2.5%, and 3% O_2

Production was at full load, steady state normal operation. The baghouse and wet FGD scrubber were in normal operation. The stack condition was saturated.

3.2 Test Protocol

The IPSC testing team performed stack testing following protocol outlined in 40 CFR Part 60, Appendix A, Methods 2, 3A, 4, and 10. A 30 minute test run was performed at each of the 12 settings and operating conditions outlined above. An extra set of tests were performed at OFA 1/3 and 2/3 full open and are also reported here for informational purposes.

The stack condition is saturated, so the calculated saturation moisture value was used for data reduction. Calculated saturated moisture is allowed in Method 4, Section 1.2.

Quality assurance and quality control consisted of following standardized testing and sample sheets, completion of protocol checklists, technical gas audits of testing and sampling equipment set-up and operation, and comparison of measured results against stack monitored values as recorded by a continuous emission monitoring system.

4.0 Test Results

4.1 CO Emissions

Measured CO emission concentration for each test were as follows:

Test Condition	Unit 2 CO (ppm)	95% Confidence Interval	Curve Fit (Y/N)
No OFA @ 2% O_2 range	140.1	44.8 - 444.3	Y
No OFA @ 2.5% O_2 range	3.2	0.0 - 240.2	Y
No OFA @ 3% O_2 range	9.8	0.0 - 218.9	Y
1/3 OFA @ 2% O_2 range	198.1	0.0 - 468.3	Y
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2/3 OFA(open) @ 3 % O_2 range	13.7	0.0 - 143.0	Y

4.2 Calculations and Curve Fit

A 95% confidence interval was developed based upon the data scatter of all CO testing. This interval was calculated against expected CO emissions predicted for a given O_2 value based upon the applicable curve. If Unit 2 CO concentration measured within an applicable CI, then the data fit the range predicted by the Unit one curve.

CO emission rates in pounds per hour (lb/hr) were calculated as required by permit. Namely, the measured CO concentration was multiplied by volumetric flow rate and required conversion factors. CO emission rates are found in the attached test spreadsheet with other calculated and measured values.

5.0 Sampling and Analysis Procedures

5.1 Emissions Testing

A. EPA Method 1; sample location for stationary sources.

The test protocol included a diagram of the Unit #1 & #2 Boiler Stack (Both stacks are identical). This reference method requires that stack geometry meets Method 1 location criteria.

B. EPA Method 2; for the determination of velocity and volumetric flow rate from stationary sources.

IPSC conducted testing using methodology consistent with EPA Method 2. Data from the runs for each test are included with field and laboratory data forms.

C. EPA 3A; for determination of oxygen and carbon dioxide from stationary sources.

This reference method requires that a gas sample be extracted from the stack for analysis. The integrated gas sample is then analyzed by instrument for carbon dioxide and oxygen.

Results from these determinations are included with field and laboratory data forms.

D. EPA 4; for the determination of moisture content in stack gases.

IPSC has substantial documentation that indicates that stack gas is saturated with moisture. Accordingly, calculated saturated moisture values for used for test calculations. These values are included with the laboratory and field data.

E. EPA 10; determination of Carbon Monoxide emissions from stationary sources.

IPSC tested CO emissions utilizing an NDIR instrument, with moisture and CO_2 traps to condition the extracted flue gas sample. The instrument was calibrated and challenged utilizing certified calibration gases. The instrument was challenged after each test run. CO concentration is calculated by adjusting the instrument reading for volumetric displacement of CO_2. Data from the runs for each test are included with field and laboratory data forms.

The test protocol included a schematic of the sampling setup used to obtain the field data. An API Model 300 analyzer was used for CO determination. In-line impingers contained silica gel and Ascarite II for moisture and CO_2 removal from the stack gas sample prior to CO determination. Stack CO_2 was determined using a California Analytical Instruments infrared analyzer. Stack O_2 was determined utilizing an Ametek Division Thermox zirconium oxide analyzer.

Test readings were recorded both electronically and on the field sheets. After analysis was completed, the instrument and sampling system was re-checked by certified gas.

Parametric values were collected from the Plant Information (PI) system. These data included values for calculated heat input, average boiler excess oxygen, portioned OFA air flow ratio, and damper positions.

6.0 Quality Control/Quality Assurance

6.1 Testing Procedures

The testing at the Intermountain Generating Station boiler stack #2 were conducted by IPSC personnel in compliance with EPA Method 10 criteria and our pretest protocol. No deviations from the prescribed testing procedures were noted.

6.2 Calibrations

Pre and post test quality checks of the instruments used are attached.

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TEST PROTOCOL